

TECHNOLOGY ASSESSMENT GUIDE
NO. 8
MOBIL COAL TO METHANOL TO GASOLINE

DRAFT

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 OVERALL PROSPECTS FOR THE TECHNOLOGY

The conversion of coal to gasoline (or other liquid hydrocarbon fuels) is an excellent technique for displacing the traditional dependence on petroleum crude oils for these fuels to a more readily available and controllable feedstock. The process can be considered as three distinct operations, the first being the gasification of coal to medium-Btu synthesis gas, followed by steam reforming of the gas to methanol. The raw methanol is then used as a feed material to the Mobil process, which catalytically converts the methanol to gasoline range hydrocarbons.

The first two steps in this conversion scheme are based upon well known, commercially established technologies. The dry-ash Lurgi gasifiers used for the coal gasification step have had over 40 years of commercial operating experience (for a complete description of this gasifier, see TAG Nos. 3 and 5). The ICI methanol synthesis process has been in wide-scale commercial use since 1966. The third stage, the Mobil MTG process, is the only step which has not been practiced on a commercial scale.

Demonstration of this important process at an adequate scale will be required before proceeding to a commercial scale facility. Current estimates of the economics of this system

appear marginal, projecting the cost of gasoline to be on the order of \$1.90/gallon at the plant site. This is inclusive of coal costs. Two factors play major roles in determining this cost: capital equipment costs and process conversion. Both of these factors are tied to the fact that the feed coal must be processed in many steps before arriving at the final desired product. Each processing step is costly in terms of capital equipment required, and also in terms of energy and material conversion efficiency. These poor conversion efficiencies are compounded by the use of a first generation dry ash Lurgi gasifier; considerable improvement could be obtained by the use of a different gasification system. Although the concept of coal to gasoline conversion is appealing, it will not become a commercial reality until a clear incentive exists.

Perhaps a better system overall would be to upgrade only a fraction of the methanol produced, blending the methanol and synthetic gasoline into one product. To do so would require the modification of new and existing carburetion systems (and a few other minor changes) to accept a lower energy density fuel. Although a change of this magnitude is considerable, it is exceeded in severity only by the nature of our fuel supply problem.

1.2 ENGINEERING ASPECTS

The first two steps in the process, Lurgi coal gasification and ICI methanol synthesis, are described in TAGS 3 and 10 respectively. The Mobil MTG (methanol to gasoline) process is the heart of this system, and only it will be discussed here.

The conversion of methanol to gasoline occurs in two major steps. The first involves the chemical dehydration of a portion of the total methanol flow to produce dimethyl ether.

After separation of the water, the mixture of methanol and dimethyl ether is reacted over another catalyst to form gasoline range hydrocarbons. Oxygen present in the methanol appears in the form of water as a reaction product, which is separated from the hydrocarbon fraction in the subsequent distillation step.

As with many synthesis operations, a spectrum of products are produced during methanol and gasoline synthesis. Gaseous compounds are recovered from the methanol synthesis, methanol conversion, gasoline fractionation and naphtha hydrotreating. The light ends are reformed (partially oxidized) with steam and oxygen to carbon monoxide and hydrogen (synthesis gas), which is used as a feed gas together with coal derived synthesis gas for methanol synthesis. This recycle of material within the process makes an important contribution to the efficient operation of the process. Even with this technique, the overall process efficiency is only 50 percent, which is significantly lower than all other coal based synthetic fuels processes of major importance. The cause of this inefficiency is twofold: 1) the use of an inefficient gasifier, and 2) the greater than normal number of processing steps required to convert the coal feedstock to gasoline. The first problem can be addressed by the use of a different gasifier, but the second problem by definition cannot be resolved within the context of the current process.

1.3 CURRENT COSTS

The total capital requirement for this 125×10^{12} Btu/year plant is \$5.5 billion, which is dominated by a plant investment of \$3.2 billion and interest during construction of \$1.8 billion. These costs are larger by

approximately a factor of two than the next largest synthetic fuels plant considered in this study. The complexity and number of processing operations required is responsible for these costs.

Annual operating and maintenance costs (at a 90% plant capacity factor) total \$253 million, which is also considerably higher than that posted by other synthetic fuels plants examined in this study. By-product credits given for ammonia and electricity offset these operating costs to a net of \$241 million annually.

Taken together with a 20 percent capital charge, these operating expenses result in a product cost of \$11.92/10⁶ Btu, exclusive of coal costs. With coal assumed to be \$1.50/10⁶ Btu, its effect on product cost would be \$3.02 (at a 49.9% conversion efficiency) for a total product cost of \$14.93/10⁶ Btu. When converted on a gasoline equivalent basis, this cost translates to \$1.86/gallon. Transportation costs and dealer markup would raise this price considerably beyond the current selling price for petroleum based gasoline.

1.4 RESEARCH AND DEVELOPMENT DIRECTIONS

As with many new processes, the first objective will be to prove the process on a large enough scale to make possible the design of a commercial facility without excessive risk. Considerable improvement can be made in process efficiency by the use of an advanced generation gasifier, although this cannot be done without increased risk. Future alterations in process configuration may also allow for not only improvements in efficiency, but decreases in capital costs as well. Such

changes could involve consolidation of two or more reaction steps within one vessel, such as direct gasoline production from synthesis gas, with or without a methanol intermediate. This concept is already being investigated by Mobil, with some interesting success to date. However, a change of this magnitude would be considered by most to constitute a new process rather than a modification to the existing one.

CHAPTER TWO: ENGINEERING SPECIFICATIONS

2.1 GENERAL DESCRIPTION OF THE TECHNOLOGY

The Mobil process described converts coal to methanol to gasoline by indirect liquefaction technology. Lurgi Mark IV gasifiers first convert the coal solids into a raw gas, which then undergoes a water-gas shift reaction to increase the hydrogen to carbon monoxide ratio. Once cooled, the shifted gas stream separates into a liquid condensate and a cleaned gas. Crude diesel oil, phenols, tars, and ammonia are recovered from the condensate prior to wastewater treatment; the cooled, cleaned gas is treated to remove acid gases and then sent to methanol synthesis reactors. Unfractionated methanol from the synthesis reactors is then converted to gasoline-range hydrocarbons for gasoline blending. Remaining gases are converted to pipeline quality SNG.

The process described in this TAG maximizes gasoline production by catalytically reforming synthesis purge gas to produce additional syngas for methanol production, and subsequently, additional gasoline. Although designed to incorporate commercial or near-commercial technologies, the Mobil MTG process represents a first-generation process for converting coal to gasoline and other liquid fuel products.

2.2 PROCESS FLOW, ENERGY, AND MATERIAL BALANCES

Plant area numbers designating process units integral to the Mobil MTG process are listed in Table 2-1. A conceptualized process flow diagram showing the relationships of the various process units is illustrated in Figure 2-1, and significant stream flows are quantified in Table 2-2. The following discussion summarizes major processing steps for the Mobil conversion of coal to gasoline.

Table 2-1

<u>Relevant Mobil MTG Plant Area Numbers</u>	
100	COAL STORAGE AND HANDLING 110 Coal Storage
200	COAL PREPARATION 210 Coal Crushing 250 Coal Sizing
300	GASIFICATION 310 Gasification 320 Ash Handling
400	HYDROGENATION/METHANOL SYNTHESIS
500	PRODUCT SEPARATION 510 Gasoline Fractionation 520 Naptha Stabilization
600	LIGHT ENDS PROCESSING 620 Gas Plant
1300	ACID GAS REMOVAL AND GAS CLEANING 1310 Acid Gas Removal 1320 Ammonia Recovery 1330 Tar and Oil Separation 1340 Phenol Recovery
1700	SHIFT CONVERSION
1800	METHANATION AND OTHER CATALYTIC REFORMING
1900	AIR SEPARATION
2000	UTILITIES AND SUPPORT SYSTEMS 2020 Wastewater Treatment
2100	OFFSITES AND MISCELLANEOUS

Figure 2-1
 Mobil MTG Conceptualized Process Flow Diagram

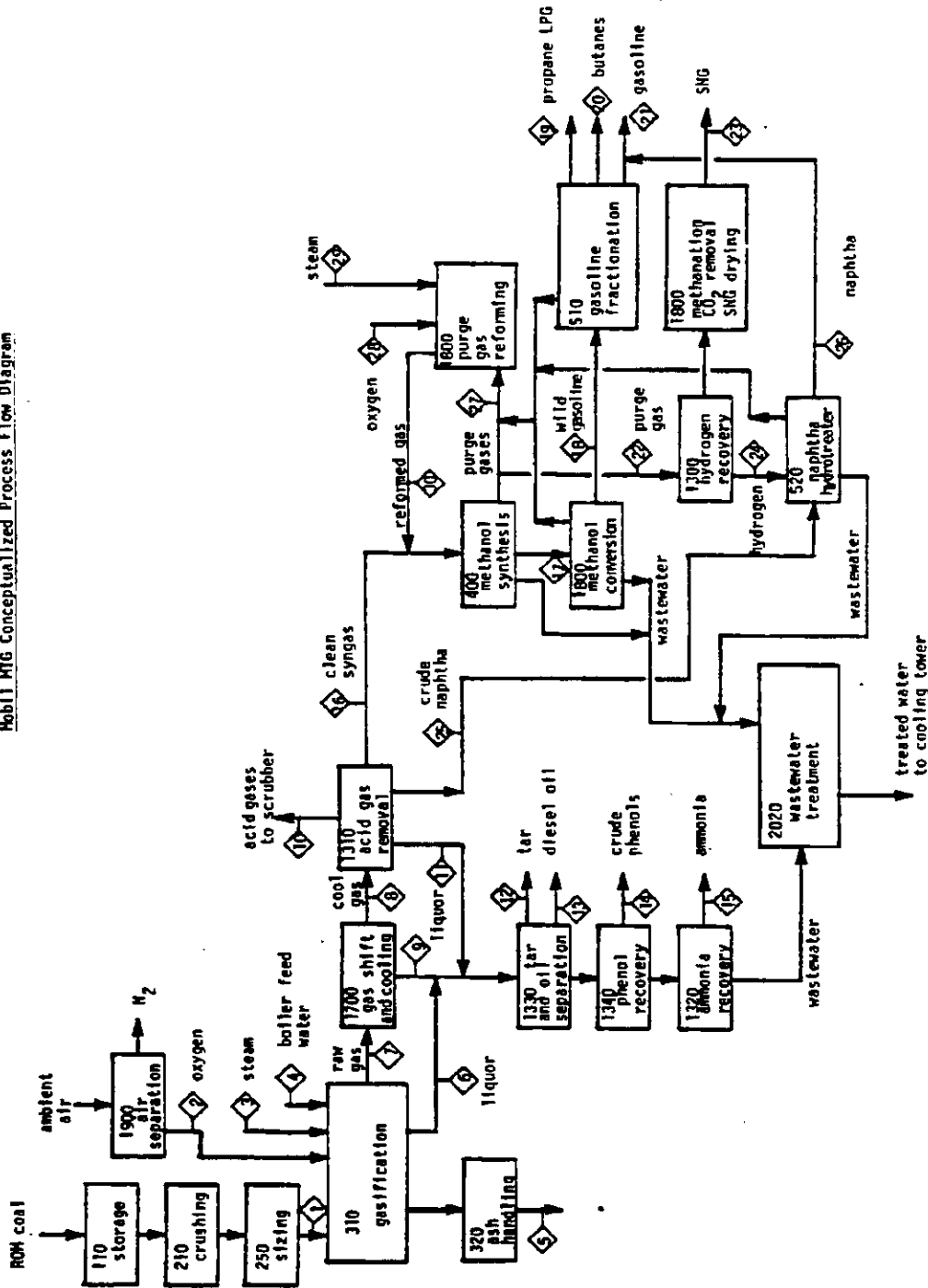


Table 2-2
Mobil MFG Detailed Process Stream Descriptions

Stream Description Temperature, °F Pressure, PSIG	1 Coal Feed		2 Oxygen		3 Steam		4 BFM to Gasifier Jacket		5 Ash		6 Gas Liquor		7 Raw Gas		8 Shifted & Mixed Gas		9 Gas Liquor		
	klb/hr	wt %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	
H ₂																			
N ₂																			
CO				0.437															
CO ₂																			
H ₂ S																			
CH ₄																			
methane																			
ethylene																			
ethane																			
propylene																			
propane																			
1-butene																			
butenes																			
n-butane																			
1-pentane																			
pentenes																			
n-pentane																			
benzene plus methanol water oxygen HCl	741.99	29.356			2213.40	100.000	253.75	100.000											
Coal	1659.06	65.640																	
Minerals	176.47	5.004																	
Oil																			
Tar																			
PH ₃																			
Naphtha																			
Crude phenols																			
Sulfur																			
Fatty acids																			
Nitrogen organic																			
TOTALS	2527.52		589.42		2213.40		253.75		135.74		350.15	5098.20		3351.14		1747.06			

Table 2-2
Mobil MTG Detailed Process Stream Descriptions

Stream Description	28		29		30											
	Flow	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr	kg/hr
Reformed Gas																
Temperature, °F		290	477	376												
Pressure, PSIG		480	535	395												
H ₂					97.48	55.235										
N ₂					53.13	2.167										
CO					547.28	22.319										
CO ₂					119.80	3.109										
H ₂ S																
CO ₂																
CH ₄																
C ₂ H ₄ ethylene																
C ₂ H ₆ ethane																
C ₃ H ₆ propylene																
C ₃ H ₈ propane																
I-butene																
butenes																
N-butane																
I-pentane																
pentenes																
n-pentane																
hexane plus																
methanol																
water																
oxygen																
HC																
coal																
minerals																
tar																
NH ₃																
naphtha																
crude phenols																
TOTALS		332.05	141.29	1082.14	212.74	13.480										

Run of mine coal is first crushed to minus 2 inch mesh, dry screened for removal of the 2" x 1/2" sized coal, and wet screened for separation of 1/4" x 0" size from the 1/2" x 0" size coal. The 1/4" x 0" coal cannot be fed to the Lurgi gasifiers and is therefore used as boiler feed. Extra coal required for the boilers is removed from the gasification unit coal feed stream.

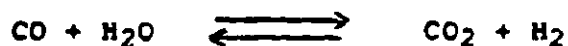
The well-sized coal is fed into Lurgi Mark IV gasifiers (210) from top-mounted coal lock hoppers. While traveling down through the gasifier, the coal is dried, devolatilized and gasified by a mixture of oxygen and steam which is introduced into the bottom of the gasifier through a rotating grate. Ash is removed by this grate and discharged to the ash handling unit (320). The addition of steam moderates the gasifier temperature to below the ash melting point.

The hot raw gas leaving the gasifier is cooled and scrubbed with recycled gas liquor. By this operation the crude gas is saturated with steam and the dust and heavy tars are removed. After further cooling, the raw gas is then sent to the raw gas shift (1700) and cooling unit.

The dusty gas liquor leaving the wash cooler is sent to the gas liquor separation unit for recovery of tars and light oil (1320), phenol (1340), and ammonia (1320).

The raw gas shift unit increases the H₂/CO ratio in the raw synthesis gas to meet the requirements of methanol

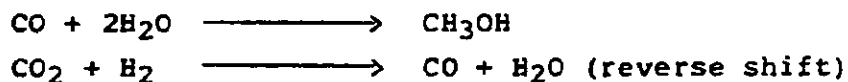
synthesis. Carbon monoxide concentration is reduced and additional hydrogen is produced by the following exothermic shift reaction:



Reaction steam is provided by the normal steam content of the raw gas. Only a portion of the raw gas from the gasifiers is fed to the raw gas shift unit. The remaining raw gas is cooled, then later mixed with the shifted gas prior to acid gas removal.

The acid gas removal unit (1310) removes sulfur compounds (primarily hydrogen sulfide) to less than 0.1 ppm in order to protect the downstream methanol synthesis unit catalyst. The unit also removes CO₂ from the gas, as well as naphtha and HCN. A non-selective Rectisol unit with a naphtha pre-wash section is used in this process.

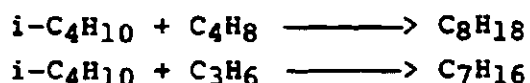
Cleaned synthesis gas enters the Imperial Chemical Industries (ICI) low pressure methanol synthesis unit (400), where the following two major reactions occur:



Raw methanol produced in this unit is fed directly to the methanol conversion process.

In the Mobil fixed bed methanol to gasoline (MTG) process, methanol is first partially dehydrated to a mixture of methanol, dimethyl ether, and water. The alcohol and ether then pass over another catalyst converter to form gasoline hydrocarbons. The produced hydrocarbons are predominantly in the gasoline boiling range (C₄ to C₁₀) and consist of highly branched paraffins and olefins, naphthenes, and aromatics. Essentially, no hydrocarbons larger than C₁₀ and no oxygenates are produced.

The raw MTG feed stream enters the gasoline fractionation unit (510), which refines the hydrocarbon products into stabilized gasoline, LPG, and a mixed butane stream. Hydrofluoric acid (HF) alkylation is used to react isobutane with olefins to form high-octane isoparaffins according to the following reactions:



Hydrofluoric acid is used to catalyze these reactions. The alkylation product is a valuable gasoline blending feedstock.

To maximize the production of gasoline hydrocarbons, purge gas from the methanol synthesis unit (400), is diverted to two processes: purge gas reforming (1800), and hydrogen recovery (1300), for use in naphtha stabilization (520). The oxygen-blown Lurgi catalytic partial oxidation process (autothermal reforming) is used to reform the high methane content purge gas from various processing units (see Figure 2-1) into a syngas suitable for recycle to methanol synthesis (and ultimately to gasoline fractionation).

The purpose of the hydrogen recovery unit is to recover hydrogen from the purge gas for later use in naphtha hydrotreating. Hydrotreatment of the naphtha stream removes any sulfur and nitrogen, improves odor, stabilizes the naphtha, and produces a stream suitable for gasoline blending.

An overall Mobil MTG indirect liquefaction plant material and energy balance is shown in Table 2-3. A total coal input of 40,360 tons per day is necessary to generate 125×10^{12} Btu/yr of liquid and gaseous fuel products. MTG gasoline represents approximately 75 percent of the product slate's energy content. Maximizing gasoline production requires additional steam and oxygen demands (compared to other indirect liquefaction processes), thus the overall plant efficiency of 49.9 percent is somewhat lower than that for other processes.

2.3 PLANT SITING AND SIZING: ISSUES AND CONSTRAINTS

The Mobil MTG indirect liquefaction process assessed in this study is designed to produce the equivalent of 125×10^{12} Btu/yr of coal-derived gasoline and other liquid and gaseous fuel products. Related process needs will include a captive coal source, wastewater treatment facilities, sludge and ash treatment and disposal areas, air separation and compression, process cooling towers, and a source of fresh water.

Subbituminous coal resources must be provided at a secured rate of 14.7 million tons per year for the life of the plant. Coal preparation facilities at the plant site include a railyard capable of receiving and dumping over

Table 2-3
Overall Material and Energy Balance

<u>Input</u>	<u>klb/Day</u>	<u>High Heating Value</u> <u>10⁹ Btu/Hr</u>
Coal to plant (includes coal fines)	80728 ^a	686.9
Steam	54500 (internally generated)	
Oxygen	22115	
Water (makeup)	70130	
 <u>Products</u>		
Gasoline	12299	254.8
SNG	1039	21.9
Propane LPG	479	10.3
Mixed butanes	966	20.3
Crude diesel oil	1613	27.9
Crude phenol	479	7.3
		<u>342.5</u>
 <u>Byproducts</u>		
Ammonia	220	2.6
Electrical power		1.5
 <u>Overall Process Efficiency</u>		 49.9%

^aRepresents ROM coal. MAF Coal = 54000 Klb/day

400 coal hopper cars a day. Other preparation facilities include a long term crushed coal storage pile (60 day supply), a five million gallon water reservoir for the wet screening unit, and various intermediate coal storage hoppers and silos.

Nearly 13 million tons/yr (approximately 9500 acre-feet) of fresh makeup process water are required. Fresh water is needed for the cooling tower, coal preparation, flue gas desulfurization, steam generation, and general services. Fresh water makeup is not readily available in large quantities in northeastern Wyoming. Therefore, the plant design minimizes fresh water consumption by utilizing recycle water streams and as much air cooling as possible. Water is obtained from deep water wells situated at 1000 foot intervals along the facility plot site. This water is pumped to a 2.5 million gallon reservoir for surge control.

Solid waste disposal facilities must safely store ashes from the gasifiers, gypsum sludge from flue gas desulfurization, and concentrated waste water sludges. Approximately 1000 acres must be devoted to landfill for the generated solid wastes. The landfill is lined with a compacted bentonite/soil layer for permeability control. No leachate collection system should be needed due to the relatively high evaporation rate in northeastern Wyoming.

2.4 RAW MATERIALS AND SUPPORT SYSTEM REQUIREMENTS

2.4.1 Coal Quantities and Quality

It has been assumed that this gasoline production plant is located in northeastern Wyoming and uses subbituminous coal similar in composition to coal from the Wyodak deposit. Proximate and ultimate analyses for the design coal are listed in Table 2-4. Approximately 25 percent of the incoming coal is used as boiler feed for steam generation. Well-sized coal (1/4" x 2") is fed to the gasifiers at a rate of 30,300 tons/day.

2.4.2 Catalysts and Other Required Materials

No quantified information is available concerning catalyst makeup requirements throughout the facility. The methanol synthesis (400) and conversion (1900) units represent proprietary processes, and no information on the catalytic materials used is available.

2.4.3 Water Requirements

The Mobil MTG facility will require approximately 8.4 million gallons (26 acre-feet) of fresh water every day. This quantity represents a minimum requirement when water conservation and recycle techniques are used. Wet cooling tower makeup is a major user of fresh water; other processes requiring fresh water makeup include: coal preparation, flue gas desulfurization, boiler feed water, and general services.

Table 2-4
Coal Composition

Proximate Analysis (as received), wt %	
Moisture	28.0
Ash	5.1
Fixed Carbon	33.8
Volatile Matter	<u>33.1</u>
Total	100.00
Ultimate Analysis (MAF basis) wt %	
Carbon	74.45
Hydrogen	5.10
Oxygen	19.22
Nitrogen	0.75
Sulfur	0.45
Chlorine	<u>0.03</u>
Total	100.00
Ash Softening Temperature, °F	2335
Ash Flow Temperature, °F	2430
Hardgrove Grindability Index	60

Section 2.7.2 discusses several of the water recovery and recycling systems proposed for the plant site. Fresh water is provided by deep water wells situated at 1000 foot intervals along the plot site.

2.5 EFFECT OF COAL TYPE

The design coal used for this plant is a subbituminous coal feedstock similar in composition to the Wyodak deposit in northeastern Wyoming. Other coal types may be used, although certain parameters may require modification, as discussed below.

Subbituminous and other low-rank coals are highly reactive in gasification processes, compared to higher-ranked coals. When utilizing a dry bottom fixed-bed gasifier (as in this plant design), reaction rates for low-rank coal gasification remain high even at the lower temperatures required to maintain dry ash conditions.

Moisture content of the feed coal is not a significant concern in Lurgi dry ash gasifiers. In fact, large amounts of steam are injected into the gasifier to maintain temperature levels below the ash melting point.

Since the chemical composition of the feed coal determines CO, CO₂, and H₂ proportions in the synthesis gas, operating conditions in the shift conversion unit may require adjustment to account for variations in coal composition. Given the proper mixture of reactant gases, methanol synthesis and conversion processes can operate without adjustment.

Variations in coal composition, even when successfully controlled by way of process modifications, may alter the product slate proportions estimated for this design. The devolatilization of oils, phenols, naphthas, and other components will

require different separation and treatment systems for higher-rank coal feedstocks due to differences in composition and feed rate.

2.6 AIR POLLUTION CONTROL TECHNOLOGY

2.6.1 Ability of Existing Technology to Meet Regulations

This plant is designed to meet existing environmental requirements for atmospheric discharges. The only discharges to the atmosphere anticipated throughout the Mobil MTG facility result from the steam generation coal-fired boiler and from various process vent streams.

A flue gas desulfurization (FGD) unit is used to remove sulfur dioxide and residual fly ash from the steam boiler stack gas. Flue gases from the high and medium pressure boilers are treated separately by limestone slurry scrubbing.

An incinerator is used at the plant site to combust sludge cake from the wastewater treatment unit, as well as combustible plant trash. Raw diesel oil from the liquor separation unit is used to fire the solids in the incinerator. Atmospheric discharges from this unit may include particulates and various unburned hydrocarbons. Emissions have not been quantified, although the use of a baghouse may be necessary to control particulate discharges. No other significant pollutants are anticipated.

2.6.2 Impacts on Process Efficiency

The use of flue gas desulfurization as a means of sulfur control has been selected in conjunction with the selection of the non-selective Rectisol acid gas removal

process. When a non-selective Rectisol unit is used to treat synthesis gas, and the sulfur content of the feed coal is very low (0.45 wt %, MAF basis), FGD systems can be considered an alternative to a selective Rectisol-Claus/SCOT sulfur recovery unit. The use of FGD requires less overall water consumption, and represents the favorable choice for process efficiency, especially since an FGD unit is already required for control of emissions from the process steam boilers.

2.7 WATER POLLUTION CONTROL TECHNOLOGY

2.7.1 Ability of Existing Technology to Meet Regulations

Although no aqueous effluent standards relating specifically to coal conversion plants have been established, standards do exist for similar non-process conventional sources (e.g. coal-fired boilers blowdown, cooling tower blowdown, etc.). Projected and existing effluent standards for coal liquefaction processes are listed in Table 2-5. The facility is designed to meet all existing effluent standards and regulations.

2.7.2 Water Recycling Systems

Water conservation is a major environmental concern in the west, and is a significant design consideration throughout this plant. Wherever possible, water usage has been eliminated, reduced, or recycled, as the following examples illustrate.

Table 2-5

Liquid Effluents-Coal Liquefaction Facilities

Source/Pollutant	Existing Requirements ^a	Projected 1990 Requirements (Base Case)	Stringent 1990 Requirements
PROCESS			
• Sour Water	N/A		Zero discharge
BOD ₅		5.0 mg/l	
TOC		10.0 mg/l	
COD		25.0 mg/l	
Oil and Grease		20.0 mg/l	
pH		6.0-9.0	
Priority Pollutants		0.5 mg/l ^b	
• Acid Gas Removal/Sulfur Recovery Blowdown	N/A	Zero discharge of water from acid gas or sulfur removal process.	Zero discharge
• Ash Sluicing Water	N/A	Zero discharge of ash transport water	Zero discharge
NONPROCESS			
• Boiler Blowdown			
TSS	100 mg/l ^c	Zero discharge	Zero discharge
Oil and Grease	20 mg/l ^c		
Copper, Total	1.0 mg/l ^c		
Iron Total	1.0 mg/l ^c		
• Once-Through Cooling Water			
Free Available Chlorine	0.5 mg/l	0.5 mg/l ^e	(0.1 Total Residual Chlorine) ^d
• Cooling Tower Blowdown-Recirculating Type			
Free Available Chlorine	0.5 mg/l	0.5 mg/l of priority pollutant discharge on a case by case basis.	(0.1 Total Residual Chlorine) ^d Zero discharge of priority pollutants.
• Bottom Ash transport			
TSS	100 mg/l ^c	100 mg/l ^c	Zero discharge of bottom ash transport water.
Oil and Grease	20 mg/l ^c	20 mg/l ^c	
		0.4 mg/l of priority pollutant discharge on a case by case basis.	
• Fly Ash Transport			
TSS	100 mg/l	100 mg/l	No discharge of fly ash water.
Oil and Grease	20 mg/l	20 mg/l	
		0.5 mg/l priority pollutants on a case by case basis	
• Low Volume Wastes ^d			
TSS	100 mg/l ^e	100 mg/l	Zero discharge
Oil and Grease	20 mg/l ^e	20 mg/l	

^aThe pH of all discharges, except for Once-Through Cooling Water, shall be within a range of 6.0 to 9.0.

^bOn a case-by-case basis.

^cMaximum for any one day.

^dIncludes coal pile runoff and leachate, fireside cleaning wastes.

^eTotal residual chlorine.

Source: Reference 2-1

Process condensate from the Lurgi gasifiers is treated and reused as makeup for the 550 psig steam generation system. By using less extensive treatment processes, the water can be used as cooling water makeup. Most other wastewater streams, following treatment, are routed to the cooling tower. Even after maximizing the practical usage of air cooling (dry cooling) techniques, cooling water requirements remain a major water consumer in the plant.

Following the guidelines to design a "zero-discharge" facility, wastewater streams are treated and sent to the cooling tower as makeup. The estimated water analyses for each of these treated streams indicate that these streams are of good enough quality to be used as cooling water. If these treated waters are later found to be unsuitable as cooling tower makeup, either more treatment will be necessary or the waters will be routed to evaporative ponds.

A storm sewer system is provided to process rain and wash water from the plant for further use. Rain water drained from the plant surface is held in a storm holding pond and then pumped to an oil separation facility. After removal of contaminants, the clean water is sent to the cooling tower as makeup.

Acid water from the methanol conversion unit is biologically treated to remove organic compounds, chlorinated to destroy microorganisms from the biological treating and then run through a gravity filter to remove suspended solids. This water should be low in dissolved solids and of sufficient quality for cooling tower operation.

2.7.3 Impacts on Plant Efficiency

Overall plant efficiency would be theoretically improved if every water-related process unit utilized a once-through water loop. However, such an approach is not feasible in any location, and especially in the semi-arid climate of northeastern Wyoming. The increased costs and reduced efficiencies of extensive water recycling must be compared to the option of long distance water shipments (surface pipelines) or numerous water wells. In this comparison, plant efficiency is most likely maximized by using extensive recycling.

2.8 SOLID WASTE HANDLING

2.8.1 Disposal Requirements

Onsite solid waste disposal procedures have been designed to meet the regulations outlined in the Resource Conservation and Recovery Act (RCRA). The solid wastes generated consist of ash from the gasifiers and boilers, gypsum sludge from flue gas desulfurization, and concentrated waste water sludges.

Two solid waste disposal options have been considered for use with this indirect coal liquefaction plant. Both are in conformance with baseline projected future EPA standards for solid waste disposal. The first alternative is a clay-lined landfill; the second alternative uses chemical fixation prior to disposal.

The landfill would require approximately 1000 acres of land, and approximately 1.1 million tons of bentonite for use in the clay/soil liner. Approximately 20 percent of the landfill would be soil used to cover waste at intervals prescribed by proposed EPA standards.

Chemical fixation circumvents the need for a clay liner, yet necessitates the addition of a fixation process facility and the purchase of quicklime and supplemental flyash.

2.8.2 Leachate Problems

It is estimated that no leachate system is required for either landfill alternative, since the mean evaporation rate exceeds the mean precipitation rate by more than 20 inches per year.

2.9 OSHA ISSUES

Handling and storage of coal will expose workers to coal dust and to noise. Coal dust can cause black lung disease. Coal dust and the coal pile can also spontaneously ignite. Dust can be controlled by wetting the coal pile.

Gasification by-products, such as tars and phenols, contain known carcinogens and co-carcinogens (agents which promote cancers). Exposure to these liquid by-products could occur during maintenance or cleaning operations and must be minimized.

Neither methanol nor Mobil methanol-to-gasoline products are known to be carcinogenic.

2.10 PROCESS PERFORMANCE FACTORS

2.10.1 Product Characteristics and Marketabilities

The principal coal-derived product produced by the Mobil MTG indirect liquefaction plant is gasoline, with secondary products that include SNG, butane, propane, diesel oil, and phenols. Ammonia is also generated but is considered a process by-product with no profitable market. The characteristics of these products are described below.

● Gasoline: Gasoline produced by the Mobil MTG process consists of blended butanes, alkylate, naphtha, and stabilized gasoline. It is a premium quality motor fuel and meets all specifications for unleaded gasoline with an octane number $[(R+M)/2]$ of 88. Its volatility and composition are similar to present-day gasolines. The composition of Mobil MTG gasoline fuel is listed below.

<u>Compound</u>	<u>Weight %</u>	<u>Volume %</u>
Mixed Butanes	2.5	-
Alkylate	2.8	-
Stabilized Gasoline	90.9	-
Hydrotreated Naphtha	3.8	-
Paraffins	-	51
Olefins	-	11
Naphthenes	-	9
Aromatics	-	<u>29</u>
	100	100

This gasoline product can be marketed as conventional unleaded regular motor fuel.

● SNG: Substitute natural gas produced by the Mobil MTG process can be marketed for either industrial or residential use as a gaseous fuel. It exhibits a heating value of 925 Btu/scf, and consists of the following components:

<u>Compound</u>	<u>Mole %</u>
H ₂	1.5
CH ₄	91.2
CO ₂	0.1
Inerts (N ₂ + Ar)	<u>7.2</u>
	100.0

The SNG, however, does not meet American Gas Association (AGA) standards for natural gas properties. As produced, the SNG exhibits satisfactory flashback and yellow tip indices, but has a flame lifting index above the objectionable level. The

is no blend of propane or butane which will result in two of the three indices being better than the "preferred" value without the third index exceeding the "objectionable limit." Blending can, however, produce an SNG within objectionable limits, although the marginal improvement in marketability may not justify the additional processing.

• Propane LPG: The produced LPG meets commercial propane LPG specifications, as indicated below:

<u>Indicator</u>	<u>Specification</u>	
	<u>Mobil MTG Propane LPG</u>	<u>Commercial Propane Standard</u>
Vapor Pressure at 100°F (max. psig)	179	208
Volatile Residue, Butane and heavier (max. vol %)	2.2	2.5
Sulfur (grains)	none	15

The propane is of satisfactory quality and can be marketed as conventional LPG.

• Mixed Butanes: These products meet commercial butane LPG specifications and can be marketed as conventional butane fuel. Commercial butane specifications are compared to the Mobil MTG butane product below:

<u>Indicator</u>	<u>Specification</u>	
	<u>Butane MTG Propane LPG</u>	<u>Commercial Butane Standard</u>
Vapor Pressure at 100°F (max. psig)	51	70
Volatile Residue, Pentane and heavier (max. vol %)	0.5	2.0
Sulfur (grains)	none	15

● Crude Phenols: The composition of phenol produced by the Mobil MTG plant is proprietary in order to protect the process operational parameters.

● Crude Diesel: The composition of phenol produced is proprietary in order to protect the process operational parameters.

2.10.2 Capacity Factors, Flexibility, Reliability

This Mobil MTG plant is designed to operate with a 90 percent capacity factor and to produce coal-derived liquid fuels at approximately 50 percent overall thermal efficiency. It has been designed for minimal risk and high service factor, largely due to redundant process trains. With the exception of the Mobil methanol-to-gasoline processes, all major reactor systems have been proven commercially. The overall plant service factor is estimated to be 81 percent for the first one to two years.

After one to two years, instrument and electrical system problems will be overcome, better data will be available for methanation, methanol conversion and reforming catalyst, and unscheduled down time will be minimized. After two years a 90 percent service factor is estimated.

Commercialization of the design as well as determination of the flexibility of the plant will require development work on both the individual plant units and their overall compatibility.

2.11 TECHNOLOGY STATUS AND DEVELOPMENT POTENTIAL

2.11.1 Current Status

The indirect liquefaction process uses gasifiers and major reactor systems that are available commercially, and all auxiliary subprocesses have been demonstrated in test operators of substantial duration in at least pilot plant facilities.

With the exception of the Mobil MTG processes, all major reactor systems have been proven commercially. The Mobil MTG fixed bed process has been demonstrated in a pilot plant and plans are now underway to design and construct the first commercial plant.

2.11.2 Key Technical Uncertainties

Although the plant design represents a minimum technical risk, there are several areas that should be studied in order to optimize reliability and efficiency. Three specific areas are discussed below.

● Gas Shift Catalysts: Lurgi has developed technology to shift the H_2/CO ratio to a value necessary for methanol production using commercial catalysts for CO conversion. Although Lurgi guarantees the process, it has been used at the demonstration scale only. Some risk is involved due to the lack of commercial plant experience. In this and other examples where processes have not been commercially proven, multiple trains are provided to improve reliability.

● Purge Gas Methanation: The methanation reaction is highly exothermic and runaway reactions are possible, resulting in damage to the catalyst. High pressure operation with the selected catalyst (unspecified) has not been commercially proven, although the methanation process in general is a proven technology.

● Water Consumption/Power Consumption Tradeoffs: All possible design steps were utilized to minimize the consumption and net discharge of water in this plant. A more thorough analysis of all process areas is required in order to optimize plant efficiency and water usage.

It was discovered in reference 2-1 that the actual saving in cooling water is smaller than initially estimated, and that significant penalties in efficiency and operating cost result by using medium pressure boilers for gasification steam. Another efficiency penalty may be the extensive use of air coolers instead of water coolers.

2.11.3 Availability for Commercial Production

The Mobil MTG plant described in this report utilizes commercially available and, for the most part, commercially proven technologies. The likelihood of actual construction and operation of this plant will depend on a number of factors involving both engineering and economic considerations. Assuming favorable regulatory, financial, and market conditions exist, the Mobil MTG plant would be available for commercial production at any location close to sufficient coal land and water resources.

2.11.4 Unit Design and Construction Times

Start-up of the Mobil MTG facility is estimated to occur within five years from the initiation of final engineering design; four years from actual site preparation.

2.12 REGIONAL FACTORS INFLUENCING ECONOMICS

2.12.1 Resource Constraints

As described in section 2.4, the coal feedstock must be supplied at a secured rate of 14.7 million tons per year for the life of the plant. In addition, nearly 13 million tons (9500 acre-feet) of ground water are required per year as makeup water for the plant processes. It is difficult to obtain both resources in sufficient quantities at any one location in the U.S. The plant described in this TAG is sited for convenient access to abundant coal resources; water supply and its conservation represent major technical and economic design considerations due to the relative scarcity of this vital process feedstock.

References

- 2-1. Wham, R.M., J.F. Fisher, R.C. Forrester III, and others. Liquefaction Technology Assessment - Phase 1: Indirect Liquefaction of Coal to Methanol and Gasoline Using Available Technology, Oak Ridge National Laboratory, ORNL-5664, February 1981.

CHAPTER THREE: ECONOMIC ANALYSIS

This section contains information on the costs of the Mobil methanol to gasoline process.

3.1 Methodology and Introduction

3.1.1 Economic Analysis Methodology

The economic analysis relies on a conceptual design for a commercial scale Mobil MTG coal to methanol to gasoline plant (3-1). The economic information presented in the report was adjusted for inflation, contingencies were added and the data was scaled to a plant size of 125 trillion Btu/year using the methodology explained in the Background Section.

3.1.2 Scaling Exponents

The reference plant was designed with a capacity of 100.5×10^{12} Btu/year of hydrocarbon fuels. This was scaled upward to 125×10^{12} Btu/year. The scaling exponents used in each area and unit are shown in Table 3-1. The scaling exponents were derived from a comparison of the costs of a one-quarter scale (3-1, pp. 92-97) coal to methanol plant to the reference plant. The scaling exponent for the product separation area (Area 500) was derived judgmentally by ERCO.

TABLE 3-1
SCALING EXPONENTS^a

AREA or UNIT	SCALING EXPONENT
200, 1330, 1400, 2000, 2100	.6
300, 1200, 1310	.9
400, 1700	1.0
1320	.8
1900	.93
500	.7

^aSource: Derived from 3-1 by ERCO

3.1.3 Price Indices

Costs for the reference plant were presented in 1979 dollars which were corrected to 1980 dollars using the methodology explained in the Background Section.

3.1.4 Economic Criteria

The standard economic criteria discussed in the Background Section were used to estimate the total capital requirement and the plant product costs. The construction period is five years with a schedule of construction expenditures of 9.2%, 24.2, 42.0, 22.3 and 2.3 percent in years one through five of construction.

3.1.5 Contingencies

A project contingency of 15 percent was added to the Total Plant Investment not including the process contingency. The

project contingency is meant to cover increased costs which usually arise as plant designs are made more complete.

A process contingency of 10 percent was added to the costs of Area 1200 and 1800, Raw Gas Cooling, and Methanation. Both of these sections have some technical uncertainty. A 25 percent contingency was applied to the cost of the methanol to gasoline synthesis unit, which has not been commercially demonstrated. This contingency added 10 percent to the cost of Unit 410, Reaction, in Area 400, Hydrogenation.

3.2 Capital Costs

The MTG plant would require huge amounts of capital, with total plant investment amounting to \$3232.7 million, as is shown in Table 3-2. The largest contributor to this cost is the Steam Generation and Power Recovery section, unit 2010, at \$552.8 million. The Reaction section, unit 410, where methanol synthesis and gasoline synthesis take place, would add \$496.3 million, or 18 percent of the total. Because of the large oxygen needs of the gasifier, Air Separation would cost \$274.2 million, or 9.9 percent.

The total capital requirement of the plant amounts to \$5500.6 million. A very large portion of this cost is Interest During Construction, at \$1837.2 million. Interest During Construction is large because the plant has a long construction period. Working Capital, Start-Up and Catalysts and Chemicals are relatively minor contributors to the capital requirement. The largest contributor to the capital requirement is the Plant Investment, of \$3232.7 million, as is shown on Table 3-3.

TABLE 3-2

TOTAL PLANT INVESTMENT: MOBIL MTG^a

AREA	UNIT	ITEM	COST 10 ⁶ \$	PERCENT OF SUBTOTAL ^d
100		Coal Storage and Handling	(see 200)	
200		Coal Preparation	205.8	7.4
300		Gasification	217.5	7.9
400		Hydrogenation		
	410	Reaction	496.3	18.0
	420	Primary Separation	3.4	.1
500		Product Separation and Processing	15.7	.6
1200		Raw Gas Cooling	14.6	.5
1300		Acid Gas Removal and Gas Cleaning	-	-
	1310	H ₂ S and CO ₂ Removal	149.1	5.4
	1320	Ammonia and Phenol Recovery	46.0	1.7
	1330	Tar and Oil Separation	33.3	1.2
1700		Shift Conversion	68.7	2.5
1800		Methanation	27.2	1.0
1900		Air Separation	274.2	9.9
2000		Utilities and Support Systems	-	-
	2010	Steam Generation and Power Recovery	552.8	20.0
	2020	Wastewater Treating and Water Supply	237.9	8.6
	2030	Solids Disposal	24.2	1.0
	2040	Plant and Instrument Air	.7	0
2100		Offsites and Miscellaneous	-	-
	2110	Flare and Incineration	5.6	.2
	2120	Tankage, Shipping and Receiving	156.4	5.7
	2130	Other Support Facilities	231.9	8.4
		Subtotal	2764.3	100.0
		Project Contingency ^b	414.6	-
		Process Contingency ^c	53.8	-
		Total Plant Investment	3232.7	-

^aSource: (3-1) Updated to third quarter 1980 dollars and scaled by ERCO to 125 x 10¹² Btu/yr.

^b15 percent of Total of Area and Unit Costs.

^c10 percent of Areas 1200 and 1800; 10 percent of unit 410.

^dDoes not add to 100 because of rounding.

TABLE 3-3

TOTAL CAPITAL REQUIREMENT^a

<u>ITEM</u>	<u>COST (10⁶\$)</u>	<u>PERCENT OF TOTAL</u>
Total Plant Investment	3232.7	58.8
Interest During Construction @15%	1837.2	33.4
Working Capital	197.2	3.6
Start-Up	194.0	3.5
Catalysts and Chemicals	<u>39.8</u>	<u>.7</u>
Total	5500.9	100.0

^aSource: (3-1), Updated to third quarter 1980 dollars.
Start-Up and Working Capital calculated using standard
ERCO methodology.

3.2.2 Variability of Capital Costs

The capital cost estimate was targeted to be accurate within ± 30 percent (3-1, pg. 213). Major equipment items were specified and costed. The cost of less important items were estimated. The capital cost estimate is quite detailed for a conceptual plant, and so is probably within the specified range. Adding to the accuracy of the estimate, is that, except for the Mobil MTG unit, the plant design uses only commercially available equipment.

3.3 Operating and Maintenance Costs

3.3.1 Itemized Operating and Maintenance Costs

Gross annual operating and maintenance (O & M) costs total \$252.8 million. These are partially offset by a credit for by-product ammonia and electricity totaling \$11.9 million. Net operating and maintenance costs amount to \$240.9 million, as is shown on Table 3-4.

The largest single component of O & M costs is Local Taxes and Insurance, at \$88.9 million/year, or 35.2 percent. Maintenance materials would cost \$57.4 million/year or 22.7 percent of the total. Ammonia production is fertilizer grade quality and is suitable for sale. Electricity would be sold back to the grid.

3.3.2 Variability of Operating and Maintenance Costs

The accuracy of the O & M cost estimates is well within the capital cost estimate accuracy of ± 30 percent. Fluor (3-1, p. 357) estimates the accuracy at $\pm 20\%$. Labor, solids disposal and catalyst and chemical requirements were

TABLE 3-4

NET OPERATING AND MAINTENANCE COSTS: MOBIL MTG^a

<u>ITEM</u>	<u>COST</u> <u>(10⁶\$)^b</u>	<u>PERCENT</u> <u>OF TOTAL^c</u>
Administration and General Overhead	55.3	21.9
Local Taxes and Insurance	88.9	35.2
Labor		
Operation	10.1	4.0
Maintenance	8.6	3.4
Administrative and Support	10.3	4.1
Total	29.0	11.5
Maintenance Materials	57.4	22.7
Catalysts and Chemicals	21.4	8.5
Solids Disposal	.8	.3
Total	252.8	100.0
<u>By-Product Credits</u>	(106 \$)	
Electricity	(4.9)	
Ammonia	(7.0)	
Total	(11.9)	
<u>Net O & M Costs</u>	(106 \$)	
Gross O & M Costs	252.8	
By-Product Credit	(11.9)	
Total	240.9	

^aSource: (3-1), adjusted to 125 x 10¹² Btu/yr by ERCO. 90% operating factor.

^bThird quarter 1980 dollars

^cColumn does not add to 100 percent because of rounding.

carefully estimated based on equipment requirements. Other costs were estimated using generous percentages of the capital costs.

3.4 Effect of Technology Development On Costs

Most units within the MTG plant employ mature technologies. Therefore, little cost reduction because of technology development can be expected. However, experience will cause the cost of future plants to decline. The conceptual plant design was overengineered to account for uncertainties in capacity factors. Future plants could use fewer trains. In addition, a large sum was allocated to design costs because this plant would be the first of its kind. In future plants, designers could use existing designs as a reference. Fluor estimates that the Nth MTG plant would cost 10-20% less than the conceptual plant in real dollars which corresponds to an experience factor of about 4 percent, if one assumes the technology would be mature after 15-20 plants are built.

3.5 Product Costs

The product costs have three discrete components: capital charges, operating and maintenance (O & M) costs, and coal costs. A non-fuel product cost can be computed with the capital charges and O & M costs, and the formula given in the Background Section.

The total capital requirement of the plant is \$5500.9 million from Table 3-3, and net O & M costs are \$240.9 million. Therefore, the non-fuel product cost is:

$$\begin{aligned}
 P &= \frac{(\$5500.9 \times 10^6 \times 20\%) + \$240.9 \times 10^6}{125 \times 10^{14} \text{ Btu} \times 90\% \text{ capacity}} \\
 &= \$9.78/10^6 \text{ Btu} \quad + \quad \$2.14/10^6 \text{ Btu} \\
 &\quad \text{(Capital charges)} \quad \quad \quad \text{(O \& M charges)} \\
 &= \$11.92/10^6 \text{ Btu} \\
 &\quad \text{(non-fuel product cost)}
 \end{aligned}$$

The non-fuel product cost of \$11.92/10⁶ Btu cost can be combined with a coal cost to yield a total product cost. The overall coal to product efficiency of the process is 49.8 percent. With coal assumed to be \$1.50/10⁶ Btu, the coal cost would be \$3.02/10⁶ Btu. Therefore the total energy cost would be:

$$\begin{aligned}
 E &= \$3.02/10^6 \text{ Btu} \quad + \quad \$11.92/10^6 \text{ Btu} \\
 &\quad \text{(Coal)} \quad \quad \quad \text{(Capital and O \& M Costs)} \\
 &= \$14.93/10^6 \text{ Btu}
 \end{aligned}$$

The average product cost would be \$14.93/10⁶ Btu. If all products are priced the same on a dollars per Btu basis, the \$14.93/10⁶ Btu figure corresponds to gasoline at \$1.86 gallon.

The \$14.93/10⁶ Btu figure is dominated by the capital and O & M costs of \$11.92/10⁶ Btu. In order for the price of the MTC products to be reduced significantly, the capital costs must be reduced.

References

- (3-1) Wham, R.M., et al.. "Liquefaction Technology Assessment - Phase 1: Indirect Liquefaction of Coal to Methanol and Gasoline Using Available Technology." Oak Ridge National Laboratory, ORNL-5664. February 1981.